UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Preventing Undue Discrimination and Preference in Transmission Service	Docket Nos. RM05-25-000 and RM05-17-000

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Thank you for the opportunity to appear today on behalf of the Southern Minnesota Municipal Power Agency ("SMMPA") and the Transmission Access Policy Study Group ("TAPS") to discuss an issue critical to this Commission's pro-competitive mission: how the transmission system essential to reliably supporting the development and sustenance of competitive regional generation markets will be planned and built. SMMPA and TAPS believe the Commission should require broad-based, truly interactive and collaborative regional joint transmission planning that assures nondiscriminatory treatment of all loads and timely construction of needed facilities.

SMMPA is a municipal joint action agency that generates and sells wholesale electricity. Our main customers are our members, eighteen municipally-owned utilities located mostly in south central and southeastern Minnesota. We operate a control area and recently joined MISO as a MISO Transmission Owner ("TO"), but we are also a transmission dependent utility ("TDU"). Portions of our 530 MW load are located on the transmission systems of Xcel, Alliant Energy, Dairyland Power Cooperative ("Dairyland"), and Great River Energy ("GRE"); we are dependent on the systems of others for transmission of our power supply to our load.

TAPS is an informal association of transmission dependent utilities in more than 30 states that advocates open access and vigorously-competitive wholesale markets, and for the robust transmission system needed to support them.

I. THE NEED FOR JOINT PLANNING

I'd like to start by talking about the need for joint planning. Based on SMMPA's experience, business-as-usual TO transmission planning is not working. In our region, it has produced a threadbare grid in which not even the smallest transmission service request can be granted without mitigation:

- Several years ago, SMMPA requested 1 MW of firm transmission service to deliver the output of a wind turbine to SMMPA load. The request was denied due to constraints several systems away.
- A SMMPA member with an approximately 5 MW load recently retired an aging diesel generating station (approximately 3 MW) connected to the municipal's distribution system, and added 6 MW of new diesel generation at the same location to support reliability in the community—*i.e.*, an incremental addition of approximately 3 MW. That community, along with a 15 MW electric cooperative load (with no generation), is served at the end of a 30-mile radial 69-kV transmission line. SMMPA's network transmission service request associated with the incremental 3 MW was denied, due to constraints elsewhere on the transmission provider's system. SMMPA had to pursue a facilities upgrade study and ultimately paid a portion of the costs associated with upgrading the transmission provider's system.

There is clearly something wrong with the transmission planning process if it produces a grid that cannot accommodate *de minimis* service requests without elaborate studies and facility upgrades.

These problems are worse for TDUs, like SMMPA and other TAPS members, than for large TOs. TDUs generally have dispersed, discrete loads, while the loads of a large TO that are spread throughout its network are treated as a single sink. Because of this difference in granularity, very small transmission service requests by TDUs are sometimes rejected, even if requests from the same resources would have been accepted if the large TO's load were the designated sink. Particularly in the absence of mechanisms to assure that the grid is being planned for all loads on a nondiscriminatory basis, TDUs face a greater risk that their transmission requests will be denied.

Even within MISO, TDU needs are not always being planned for adequately. MISO's regional transmission plans are based on aggregating the plans of member TOs. If large TOs have not included TDUs in a joint planning process, or if such TOs use an internal "Cost-Benefit Analysis" for proposed upgrades that does not consider TDU loads, TDU needs will not be reflected in the underlying plans that MISO aggregates.

MISO appears to have focused its transmission planning energies on specific generator interconnection requests. But without the context provided by a collaborative and interactive bottom-up joint planning process, the solutions that MISO proposes for those interconnections can be penny-wise and pound-foolish. For example, in one recent case, MISO proposed the construction of an additional transmission line, parallel to an overloaded facility identified in the generator interconnection study, that would have done nothing for the weak grid in the region. Large TOs that learned of the recommendation initiated a broader study to consider transmission solutions that addressed both the interconnection *and* other load serving needs. Because this problem was brought to the attention of TOs that were concerned about siting issues and other load serving needs in the area, there might be a happy ending in this case. However, an affected TDU would not necessarily have even been made aware of the situation. Furthermore, the experience illustrates a basic problem: reactive transmission planning driven by specific service requests will produce a patchwork of minimalist, short-term fixes—not the properly-scaled, efficient upgrades and robust grid needed to support broad competitive markets.

The transmission problems of the Minnesota/North Dakota/South Dakota region are not new; and over the years, SMMPA has been active in initiatives to address those problems on a regional level. For example, a joint transmission area, created by a 1999 FERC settlement, provided for credits for existing transmission ownership and established a non-pancaked, multi-system network transmission rate among Xcel, GRE, SMMPA, Central Minnesota Municipal Power Agency, and Dairyland. The terms of the settlement, however, did not include a mechanism to provide credits for additions to the joint system.

SMMPA also actively participated in TRANSLink, which was conditionally approved by the Commission, but never implemented.

Most recently, a number of utilities in the region, including TAPS members SMMPA, Missouri River Energy Services ("MRES"), Wisconsin Public Power Inc. ("WPPI"), and Midwest Municipal Transmission Group ("MMTG) have participated in the CapX 2020 regional transmission planning process, which appears to be producing significant positive results—both in the Phase I projects now moving forward and in the identification of projects for later phases to enable expected future generation development to serve load. While Will Kaul will provide more details on the CapX process, I will focus on lessons that the Commission can learn from CapX in considering regional joint planning requirements for the OATT.

II. WHAT CAN WE LEARN FROM CAPX 2020?

Mandatory joint planning is needed even in RTOs; if we wait for voluntary joint planning to occur, it will be too late. While we are encouraged by the preliminary results of the CapX process, CapX 2020 has only now reached the stage where our regional planning efforts *should* have been five to ten years ago. Some of the high voltage, Phase I projects currently being considered were specifically identified in studies at least five years ago (*e.g.*, Bemidji to Grand Rapids (230 kV), and Fargo to Alexandria to Twin Cities (345 kV)), but they did not proceed at that time because of the lack of sponsors. Meanwhile, system conditions continued to deteriorate, despite being subject to MISO planning obligations and processes.

Although the voluntary CapX planning process eventually emerged, it did so only after the grid was clearly broken. In our region, the system is deemed to meet reliability standards because of operational workarounds that have been adopted in lieu of facility upgrades. But because underlying grid deficiencies have not been addressed, the system remains vulnerable to problems. In recent years, there were at least two major incidents in which the regional grid was close to collapse because the network lacked the margins needed to withstand line outages caused by storms. These near-misses were an overdue wakeup call that something had to be done. The currently proposed CapX Phase I projects—which include $1.3 *billion* in upgrades primarily aimed at maintaining reliability—illustrate the severity of the underlying problems. Effective regional joint planning should have started long before the transmission system needed triage investments of this magnitude.

Transmission planning must be proactive. The CapX process is planning for long-term needs, based on long-term load forecasts and estimates of future generation additions and retirements. Planned facilities are being sized for the future—they are not band-aids designed to reactively address immediate problems created by pending service requests.

This long-term, proactive approach to transmission planning is the only one that makes sense. Just-in-time transmission investment may be the right solution for localized substation issues, but it will not work for the bulk transmission network.[1] In many cases, it takes longer to build transmission than generation. In addition, there are almost always multiple benefits to any bulk transmission investment—*e.g.*, reliability, congestion relief, loss reduction, competitive market access, access to diverse generation sources—and those benefits (and beneficiaries) may change over time. Arbitrarily categorizing upgrades into "reliability" or "economic" projects, or relying on short-term price signals to create incentives for transmission investment, will not produce a robust grid able to support competitive wholesale markets.

Collaborative, interactive joint planning can work. The CapX process includes a wide range of entities in a collaborative, interactive planning process. TDUs have not been relegated to a "bystander" role in which they are presented with completed transmission plans that have been prepared by the large TOs. Instead, TDUs have been given the opportunity to participate in and share responsibility for the underlying analyses and planning decisions. For example, MRES, a TDU that is a member of TAPS, actively participates in the CapX planning studies and has increased its in-house transmission planning staff to assure that it can continue to contribute to the regional planning effort.

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[1] For example, DOE's August 2006 nationwide study of transmission congestion, which was mandated by the Energy Policy Act of 2005, identified the Dakotas-Minnesota area as one of five Conditional Congestion Areas where transmission congestion is not currently acute, but could become so if new generation resources are developed without development of transmission capability. Designing and building transmission to address such needs will require proactive, long-term regional planning.

An effective regional joint planning process may need to encompass more than one state. TAPS supports the NOPR's goal of encouraging joint planning and coordination in regions broad enough to develop and implement effective solutions to transmission problems. As Mr. Kaul will discuss in greater detail, the CapX process, while centered in Minnesota, has had to include participants in other states to find solutions to regional transmission problems.

Joint ownership and open season requirements should not create problems, as some NOPR commenters suggest. For the proposed Phase I projects, CapX used a process in which all participants—not just large TOs—were given an opportunity to indicate their willingness to invest. The process successfully mobilized large amounts of capital, and resulted in Memoranda of Understanding from all types of entities—municipalities, joint action agencies, cooperatives, and investor-owned utilities—to support virtually all of the anticipated investment in proposed Phase I projects. Based on the CapX experience, joint ownership and open season requirements work, and encouraging TDUs to invest in transmission benefits the region as a whole. The OATT can become a vehicle to facilitate such investment, by modifying Section 30.9 to remove the joint planning prerequisite for TDUs to receive credits and clearly eliminate the TO-centric "integration" test for TDU-owned facilities. The NOPR proposes the former, and while it appears to intend the latter, more clarity is required in the final rule (as recommended in TAPS' Initial Comments) if that change is to be effective in facilitating TDU investment in the grid.

The availability of a process for resolving regional cost allocation issues and achieving broad spreading of costs provided a framework for investment commitments. CapX participants have been willing to commit to investment in major transmission upgrades, because: (1) Attachment O of the MISO Tariff provides certainty of cost recovery; and (2) MISO's RECB[2] I cost allocation rules, although still in flux, provided sufficient structure to allow CapX participants to evaluate potential transmission investments and the extent to which the cost responsibility for those upgrades would be broadly shared, rather than borne by individual participants.

Attachment O encourages transmission investment because it provides a clear mechanism for cost recovery through the MISO formula rate for MISO TOs and for TDUs who become MISO TOs through grid investment. The Commission can and should provide the same assurance to TDUs under the OATT, by modifying Section 30.9 to provide for fair crediting for the transmission upgrades that TDUs fund.

Although CapX does not have certainty from MISO with respect to the cost allocation for the Phase I projects, the CapX participants believe the projects should be considered "Baseline Reliability Upgrades" under MISO's RECB I cost allocation rules. As such, CapX participants have assumed that cost responsibility for Phase I upgrades will be shared by at least all CapX participants, if not more broadly. Absent that confidence in a methodology that broadly spreads cost responsibility, CapX participants would not have been able to evaluate the proposed investments, and many would probably have been less willing to make specific commitments.

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[2] Regional Expansion Criteria and Benefits.

Potential benefits of a "big tent" planning process. CapX's broad support among TDUs has already paid dividends in terms of enabling enactment of the state legislation needed to facilitate CapX cost recovery through formula rates at retail. CapX's broadly inclusive joint planning process should similarly increase support in the always-challenging transmission siting process. By helping participants understand local conditions and allowing them to develop a general familiarity with, and to participate in, the modeling process, joint planning should also increase customer confidence in the transmission plans, minimize disputes, and facilitate and expedite subsequent transmission planning cycles.

III. CONCLUSION

Based on our experiences, joint planning is crucial to ending the current paralysis that has resulted in an inadequate grid in many parts of the country. We believe that the NOPR is on the right track in mandating regional joint planning through the OATT. We urge the Commission to include that requirement in the final rule and apply it to *all* transmission providers—including non-RTO transmission providers, RTOs, and the member TOs that provide the transmission plans on which RTO plans are built.

We are concerned, however, that the NOPR's proposed OATT changes are insufficient to get the job done. To achieve the Commission's pro-competitive vision and satisfy Congress' mandate in the Energy Policy Act of 2005, the NOPR's eight process principles should be strengthened with:

1. The requirement that planning be collaborative and interactive;
2. Substantive planning goals designed to assure that plans developed by individual regions anticipate and proactively correct transmission inadequacies;
3. Opportunities for TDUs to invest in transmission through open season requirements, with comparable cost recovery assured through a reformed Section 30.9; and

4. A clear obligation to construct needed transmission facilities, and provisions to hold transmission providers accountable for doing so, including:

   a) With regard to network customers for whose needs the transmission providers have long been required to plan the system, requiring the transmission provider to accept a network customer's timely designated network resource, if necessary through redispatch with costs shared on a load-ratio basis until necessary upgrades are completed.

   b) At minimum, to address discrimination through granularity differences, requiring transmission providers to accept any request for transmission to a network customer load (if necessary, by redispatch shared on a load-ratio basis) if the request would have been accepted if the transmission provider's own load had been the designated sink.